MONTANA DEPARTMENT OF ENVIRONMENTAL QUALITY
OPERATING PERMIT TECHNICAL REVIEW DOCUMENT

Permitting and Compliance Division
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Helena, Montana 59620-0901

ConocoPhillips Company
Billings Refinery
NW¼, Section 2, Township 1 South, Range 26 East, Yellowstone County, MT
P.O. Box 30198
401 South 23rd Street
Billings, Montana 59107-0198

The following table summarizes the air quality programs testing, monitoring, and reporting requirements applicable to this facility.

Facility Compliance Requirements	**Yes**	**No**	**Comments**
Source Tests Required	X		
Ambient Monitoring Required		X	
COMS Required	X		40 CFR Part 51
CEMS Required	X		
Schedule of Compliance Required		X	
Annual Compliance Certification and Semiannual Reporting Required	X		
Monthly Reporting Required	X		
Quarterly Reporting Required	X		
Applicable Air Quality Programs			
ARM Subchapter 7 Preconstruction Permitting	X		Permit #2619-12
New Source Performance Standards (NSPS)	X		Subpart A, Subpart J, Subpart Ka, Subpart Kb, Subpart UU, Subpart GGG, Subpart QQQ
National Emission Standards for Hazardous Air Pollutants (NESHAPS)	X		Subpart FF
Maximum Achievable Control Technology (MACT)	X		Subpart R, Subpart CC
Major New Source Review (NSR), including Prevention of Significant Deterioration (PSD)	X		
Risk Management Plan Required (RMP)	X		
Acid Rain Title IV		X	
State Implementation Plan (SIP)	X		Billings/Laurel SIP

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SECTION I. GENERAL INFORMATION

A. Purpose

This document establishes the basis for the decisions made regarding the applicable requirements, monitoring plan, and compliance status of emission units affected by the operating permit proposed for this facility. The document is intended for reference during review of the proposed permit by the EPA and the public. It is also intended to provide background information not included in the operating permit and to document issues that may become important during modifications or renewals of the permit. Conclusions in this document are based on information provided in the original application submitted by Conoco Inc. (Conoco) on 06/12/96; subsequent settlement stipulation and order of dismissal of ConocoPhillips's Title V permit appeal, filed on 07/09/02; and two administrative amendments received 12/19/02 and 10/10/03 filed by ConocoPhillips Company (ConocoPhillips).

B. Facility Location

The ConocoPhillips Billings Refinery is located at NW¼, Section 2, Township 1 South, Range 26 East, Yellowstone County. This legal description refers to physical address of 401 South 23rd Street, Billings, Montana.

C. Facility Background Information

Montana Air Quality Permit

The refinery processes 50,000 barrels per day of crude oil and produces a wide range of petroleum products, including propane, gasoline, kerosene/jet fuel, diesel, and petroleum coke. ConocoPhillips has received several air quality permits throughout the past years for various pieces of equipment and operations. All previously permitted equipment, limitations, conditions, and reporting requirements stated in Permits #1719, #2565, #2669, #2619, and #2619A were included in Permit #2619-02.

On October 29, 1982, Conoco received an air quality permit for an emergency flare stack to be equipped and operated with steam injection. This application was given Permit #1719.

On June 2, 1989, Conoco received an air quality permit to convert an existing 5000-barrel cone roof tank (#49) to an internal floating roof with double seals. This conversion was necessary in order to switch service from diesel to aviation gasoline storage. The application was given Permit #2565.

On January 29, 1991, Conoco received an air quality permit to construct and operate two (2) 2000-barrel desalter wastewater break tanks equipped with external floating roofs and double rim seals. The new tanks are to augment the refinery's ability to control fugitive VOC emissions and enhance recovery of oily water from the existing wastewater treatment system. The application was given Permit #2669.

On April 19, 1990, Conoco received an air quality permit to construct new equipment and modify existing equipment at the refinery and construct a sulfur recovery facility, operated by Kerley Enterprises under the control of Conoco, as part of the overall Conoco project. The application was given Permit #2619. Conoco was permitted to construct a new 13,000-barrels-per-stream-day delayed-petroleum coker unit, cryogenic gas plan, gasoline treating unit, and hydrogen system additions. Also, modifications to the existing crude and vacuum distillation units, hydrodesulfurization units, amine treating units and wastewater treatment system were permitted. The sulfur recover facility (SRU/ATS) is to be operated in conjunction with the new installations and modifications at the Conoco Refinery. This SRU/ATS was permitted with the capability of utilizing 109.9 long tons per day of equivalent sulfur obtained from the

Conoco Refinery for the manufacture of elemental sulfur and sulfur-containing fertilizer solutions (i.e., ammonium thiosulfate).

On December 4, 1991, Conoco was issued Permit #2619A for the construction of one 1000-barrel hydrocarbon storage tank (T162). This tank will store recovered hydrocarbon product from the contaminated groundwater aquifer beneath the Conoco Refinery. Over the years, surface discharges at the refinery have contaminated the groundwater with oily hydrocarbon products. The purpose of this project is to recover hydrocarbon product (oil) from the groundwater aquifer beneath the refinery. The hydrocarbon product (oil) is pumped out of a cone of depression within the contaminated groundwater aquifer. Groundwater, less the recovered hydrocarbon product, is returned to the aquifer. The application addressed the increase in volatile organic compound (VOC) emissions from the storage of recovered hydrocarbon product.

On March 5, 1993, Conoco was issued Permit #2619-02 for the construction and operation of a 5.0-MMscf-per-day hydrogen plant and to replace their existing API separator system with a CPI separator system. The natural gas feedstock to the new hydrogen plant will produce 99.9% pure hydrogen. This hydrogen and hydrogen from the existing catalytic reformers will be routed to the refinery hydrotreaters to reduce fuel product sulfur content. The hydrogen sulfide produced is, and will continue to be, routed to the SRU/ATS. The two (2) new CPI separator tanks with carbon canister total VOC controls were constructed to comply with 40 CFR 60, Subpart QQQ and 40 CFR 61, Subpart FF regulations. The CPI separators vent to two (2) carbon canisters in series. Each carbon canister shall be designed and operated to reduce VOC emissions by 95%, or greater, with no detectable emissions.

Correspondence received by the Montana Department of Environmental Quality (Department) on December 22, 1992, transferred ownership of the Kerley Enterprises facility to Jupiter Sulphur, Inc. as of December 31, 1992.

On September 14, 1993, Conoco was issued Permit #2619-03 for the construction and operation of a gas oil hydrotreater and associated hydrogen plant at the Billings refinery. The new hydrotreater desulfurizes a mixture of Fluid Catalytic Cracker (FCC) feed gas oils, which allow the FCC to produce low sulfur gasoline. This low sulfur gasoline is required by January 1, 1995 to satisfy EPA's gasoline sulfur provisions of the Federal 1990 Clean Air Act Amendments. Hydrogen requirements will be met by the installation of a new hydrogen plant. Installing additional elemental liquid sulfur production facilities at the SRU/ATS plant adjacent to the refinery will provide sulfur recovery capacity. The following is a discussion of the project to accomplish this end.

The Gas Oil Hydrodesulfurizer (GOHDS) is designed to meet the primary objective of removing sulfur from the FCC feedstock. A combination of gas oils feed the Gas Oil Hydrotreater. The gas oils are mixed with hydrogen, heated, and passed over a catalyst bed where desulfurization occurs. The gas oil is then fractionated into several products, cooled, and sent to storage. A steam-methane reforming hydrogen plant produces makeup hydrogen for the unit. Any unconsumed hydrogen is amine treated for hydrogen sulfide (H_2S) removal and recycled.

The project did not increase the refinery's capacity. The project did not constitute a major modification for purposes of the Prevention of Significant Deterioration (PSD) program since net emissions did not increase above significant amounts as defined by the ARM 18.8.801(20)(a).

The additional fugitive VOC emissions from this project were calculated by totaling the fugitive sources on the process units. These sources include flanges, valves, relief valves, process drains, compressor seal degassing vents and accumulator vents, and open-ended lines. The fugitive source tabulations were then used with actual refinery emission factors obtained from the Conoco Refinery in Ponca City, Oklahoma. Furthermore, it is intended that each non-control valve in VOC service will be repacked with graphite packing to Conoco standards before installation. All control valves for the GOHDS project will be

Enviro-Seal valves or equivalent. The Enviro-Seal valves have a performance specification that exceeds the Subpart GGG standards. The VOC emissions will be validated by 40 CFR 60, Subpart GGG emission monitoring.

As a result of the project, the SRU/ATS facility will consist of three primary units. They are the existing ammonium thiosulfide ATS Plant, the existing Ammonium Sulfide Unit and the addition of the Claus Sulfur and Tail Gas Treating Units (TGTU). The addition of the new units did increase the total sulfur recovery capacity of the facility from 110 to 170 long tons per day (LT/D) of sulfur.

The existing ATS plant consisted of a thermal Claus reaction type boiler. The exit gas from the Claus boiler is incinerated in the ATS Unit. The sulfur dioxide from the incinerator is absorbed and converted to ammonium bisulfite (ABS). The ABS is then used to absorb and react with hydrogen sulfide to produce the ATS product. Up to 110 LT/D of sulfur can be processed by the ATS plant to produce sulfur and ATS.

The ammonium sulfide unit consists of an absorption column, which absorbs the sulfur as hydrogen sulfide in the acid gas feed and reacts with ammonia and water. When the new Claus sulfur unit is added, the SRU/ATS facility will be modified to incinerate any off-gas from this unit in the TGTU and ATS plant. This will eliminate off-gas flow to and emissions from the flare. Up to 110 LT/D of sulfur can be processed by the ammonium sulfide unit to produce ammonium sulfide solution.

The new Claus sulfur unit consists of a thermal Claus reaction furnace followed by a waste heat boiler and three catalytic Claus reaction beds. The Claus tail gas is then incinerated before entering the TGTU. In this new unit, the sulfur dioxide from the incinerator is absorbed and converted to ABS. This ABS is then transferred to the ATS unit for conversion. Up to 110 LT/D of sulfur can be processed by the Claus sulfur unit to produce sulfur and ABS. The ABS from the TGTU is dilute, containing a significant amount of water that was generated from the Claus reaction. To prevent making a dilute ATS from this "weak" ABS, a new ATS reactor was added to the ATS unit. This ATS reactor will combine "weak" ABS, additional ABS, and sulfur to make a full strength ATS solution.

An important feature of the Jupiter Sulphur, Inc. facility is its capability to process Conoco's sour gases at all times. A maximum of 170 LT/D of sulfur is planned to be recovered and each of the three units have a capacity of 110 LT/D. If any of the three is out of service, then the other two can easily handle the load. While the process has 100% redundancy, any two of the three units must be running to handle the design load. The process uses high efficiency gas filters, which employ a water-flush coalescer cartridge to reduce particulate, as well as sulfur compounds.

On November 11, 1993, Conoco was issued Permit #2619-04 to construct and operate a new compressor station and associated equipment at the Billings Refinery. The C-23 compressor station project will involve the recommissioning of an out-of-service compressor and associated equipment components having fugitive VOC emissions. The project will also involve the installation of new equipment components having fugitive VOC emissions. The recommissioned compressor was originally installed in 1948. The compressor will undergo some minor refurbishing, but will not trigger "reconstruction" as defined in 40 CFR 60.15. The purpose of the C-23 compressor station project is to improve the economics of the refinery's wet gas (gas streams containing recoverable liquid products) processing through increased yields and more efficient operation in the refinery's large and small Crude Topping Units (CTUs) and the Alkylation unit. The project also improved safety in the operations of the two CTUs, Alkylation unit, and Gas Recovery Plant (GRP). As a result of this project, the vapor pressure of the alkylate product (produced by the Alkylation unit) will be lower.

On February 2, 1994, Conoco was issued Permit #2619-05 to construct and operate a new butane defluorinator within the alkylation unit at the refinery. Installation of an alumina (AL_2O_3) bed defluorinator system is to remove residual hydrofluoric acid (HF) and organic fluorides from the butane stream produced by the alkylation unit. This will reduce the fluorine level of the butane from ~ 500 ppmw to ~ 1 ppmw, which will allow the butane to be recycled back to the refinery's butamer unit for conversion into isobutane. The alkylation unit butane defluorinator project resulted in: (1) changes in operation of the alkylate stabilization train of the alkylation unit to yield defluorinated butane instead of fluorinated and lower vapor pressure alkylate products; (2) changes in operations of the refinery's gasoline blending to restructure butane blending and lower the vapor pressure of the gasoline pool; (3) minimize butane sales; (4) minimize butane burning as refinery fuel gas; and (5) economize gasoline blending of butane.

On March 28, 1994, Conoco was issued Permit #2619-06 to construct and operate equipment to support a new polymer modified asphalt (PMA) unit at the refinery. The PMA project allowed Conoco to produce asphalt that meets the new federal specifications and become a supplier of PMA for the region. A 9.5-MMBtu/hr natural gas-fired process heater, to heat an oil heat transfer fluid, was installed to bring the asphalt base to 400 ºF. This allows a polymer material to be mixed with it to produce PMA. A new hot oil transfer pump was installed to circulate hot oil through the system. A heat exchanger (X-364) from the shutdown PDA unit was moved and installed to aid in the heating of the asphalt base. Two existing 5000-bbl asphalt storage tanks were converted to PMA mixing and curing tanks. This required the installation of additional agitators, a polymer pellet loading (blower) system and conversion of the tank steamcoil heating system to hot oil heated by the new process heater. New asphalt transfer line, a new asphalt transfer pump and a new 5000 bbl PMA storage tank (replacing the demolished T-50) was installed to keep the PMA separated from other asphalt products.

On July 28, 1995, Conoco was issued Permit #2619-07 for the construction and operation of new equipment within the refinery's alkylation (alky) and gas recovery plant/No.1 Amine units. This project was referred to as the Alkylation Unit Depropanizer Project. The existing Alkylation unit was replaced with a new tower. The new depropanizer is located where the No.1 Bio-pond was located. Piping and valves were added and the new depropanizer was located next to existing equipment. The old depropanizer was retained in place and may be used in the future in a non-Hydrogen Fluoride (HF) service. The decommissioned propane deasphalting (PDA) unit evaporator tower (W-3) was converted to a water wash tower to remove entrained amine from the Alky PB (Propene/Butene) olefins upstream of the PB merox prewash. New piping, valves, and instrumentation were added around W-3. The change in air emissions associated with this project were increases in fugitive VOC emissions, as well as additional emissions of fluorides due to the installation of the new depropanizer piping and valves. The changes associated with this project did not trigger PSD review because the sum of the emission rate increases is below PSD significant emission rates for applicable pollutants. The drains installed or reused tie into parts of the refinery's wastewater sewer system that are already subject to NSPS Subpart QQQ (Wastewater Treatment System VOC Emissions in Petroleum Refineries) and NESHAP Subpart FF (Benzene Waste Operations). These drains will be equipped with tight fitting caps and have hard pipe connections to meet the required control specifications.

On July 24, 1996, Conoco was issued Permit #2619-08 to change the daily SO_2 emission limit of the 19 existing process heaters, as well as combining the 19 heaters, the Coker heater (H-3901), and the GOHDS heaters (H-8401 and H8402) into one SO_2 point source within the Refinery. The project was referred to as the Existing Heater Optimization Project.

The 19 process heaters being discussed in this project are the process heaters (excluding H-3 and H-7) that were in operation prior to the construction of the Delayed Coker/Sulfur Reduction Project, which became fully operational in May of 1992. The 19 heaters are: H-1, H-2, H-4, H-5, H-10, H-11, H-12, H-13, H-14, H-15, H-16, H-17, H-18, H-19, H-20, H-21, H-22, H-23, and H-24. These 19 heaters are pooled together and regulated as one source, referred to as the "19 Heaters" source. Also included in this discussion are the Coker heater (H3901) and the GOHDS heaters (H-8401 and H-8402).

The 19 heaters had a "bubbled" SO_2 emissions limit of 30.0 TPY (164 lb/day) and a limitation of fuel gas H_2S content of 160 ppmv (0.1 grain/dscf). With both these limitations intact, all these heaters could not simultaneously operate at their maximum-design firing rates. This could cause un-optimized operation of the refinery during unfavorable climatical conditions or during peak heater demand periods. To allow all 19 of the heaters to simultaneously operate at their maximum firing rates, the allowable short-term SO_2 emissions limit for the "bubbled" 19 heaters needed to be increased. The 19 refinery fuel gas heaters/furnaces lbs/day SO_2 emission limitations were based on NSPS fuel gas (160 ppm H_2S), maximum heat input (MMBtu/hr) from the emission inventory database (AFS), and higher fuel heat value (1015 Btu/scf) from the 1990 Base Year Carbon Monoxide Emission Inventory. By using these parameters, the daily "bubble" SO_2 permit limit could be raised to 386 lb/day, as was indicated in the Preliminary Determination (PD).

Conoco requested that the daily limit be increased to 612 lb/day, which is equivalent to the rate used in the Billings SO_2 SIP modeling (111.7 tpy). The annual "bubble" SO_2 limit of 30 tpy was maintained. The Department received comments from Conoco in which Conoco contended that the maximum heat input (MMBtu/hr) from AFS did not accurately reflect the real maximum firing rates of the heaters. After further review of the files, the Department established the total maximum firing rate for the 19 refinery fuel gas heaters/furnaces to be 785.5 MMBtu/hr. ConocoPhillips identified the total maximum firing rate during the permit review of the Coker permit (Permit #2619). The maximum heat input of 785.5 MMBtu/hr and the fuel heat value of 958 Btu/scf were used to calculate the new daily "bubble" SO_2 permit limit of 529.17 lb/day.

The change in air emissions of other criteria pollutants (CO, NO_x, PM, and VOC) associated with this project was zero, since the potential to emit for these pollutants did not change. With the 164-lb/day SO_2 limit, simultaneous maximum firing of these heaters could be accomplished if the fuel gas H_2S content stayed below 49.75 ppmv. Conoco's amine systems produced fuel gas averaging (on an annual basis) about 25-ppmv H_2S content or less (see the 1993 and 1994 refinery EIS's). Since the emissions of CO, NO_x, and VOC produced are not a function of H_2S content and Conoco's amine system could generate appropriate fuel gas to stay at or below the 164-lb/day SO_2 limit, the maximum potentials of these pollutants are obtainable and not affected by this project. The PM limits for these heaters are 80 times higher than the amount generated by fuel gas combustion devices (see ARM 17.8.340); therefore, the PM emissions potential is not affected as well.

Even though Conoco's past annual average fuel gas H_2S content had been below 37.8 ppmv, there would still be potential to run into operational limitations in peak fuel gas demand periods. The amine systems may not have been able to keep the fuel gas H_2S under 49.75 ppmv, rendering the refinery to operate at un-optimal rates. This was the reason for the request to raise the daily SO_2 emissions limit for the 19-heater source.

Since the proposed change to the heaters' SO_2 emissions limit does not reflect an annual increase in potential to emit, the project did not trigger PSD permitting review (threshold for SO_2 is 40 TPY).

In light of the SO_2 problem in the Billings-Laurel air shed, any change resulting in an increase of SO_2 emissions must have its impact determined to see if any National Ambient Air Quality Standards (NAAQS) will be violated as a result of the project. SO_2 modeling was completed by the Department to develop a revised SO_2 State Implementation Plan (SIP) for the Billings-Laurel area. The "19-heater source" was modeled using an SO_2 emission rate equivalent to 111.7 tpy to determine its existing SO_2 impact on the Billings-Laurel air shed. The results of this modeling showed there were no exceedances of the SO_2 NAAQS or the Montana standards resulting from it operation. Therefore, an increase in the permit limit from 164 lb/day to 612 lb/day of SO_2 will not result in any violations of SO_2 NAAQS or the Montana standards. However, the daily emission limits set based on the NSPS limit of 0.1 grain/dscf

(160 ppmv H_2S) are more restrictive that the SIP limit. The daily emission limits set based on NSPS is 529.17 lb/day for the existing 19 heaters/furnaces.

In addition to changing the daily SO_2 permit limit for the "19-heater source", Conoco requested that the "19 heater source", the Coker Heater (H-3901), and the GOHDS heaters (H-8401 and H-8402) be combined into one permitted source called the "Fuel Gas Heater" source. Using the existing daily SO_2 permit limits for the Coker heater and GOHDS heaters, an overall SO_2 emissions limit "bubble" of 614 lb/day would apply to the "22-Fuel Gas Heaters" source. The annual limit for the "22-Fuel Gas Heaters" source has not changed and is 45.50 tpy (30.00 + 9.60 + 2.90 + 3.00).

On April 19, 1997, Conoco was issued Permit #2619-09 to "bubble" or combine the allowable hourly and annual NO_x emission limits for the Coker Heater, Recycle Hydrogen Heater, Fractionator Feed Heater, and Hydrogen Plant Heaters. The NO_x emission limits for these heaters were established on a pounds-per-million-Btu basis and will be maintained. By "bubbling" or combining the allowable hourly and annual NO_x emission limits for the Coker Heater, Recycle Hydrogen Heater, Fractionator Feed Heater, and Hydrogen Plant Heaters would allow Conoco more operational flexibility with regard to heater firing rates and heater optimization. The Coker heater will still have an hourly NO_x emission limit to prevent any significant impacts. The permitting action did not allow an increase in the annual NO_x emissions.

On July 30, 1997, Permit #2619-10 was issued to Conoco in order to comply with 40 CFR 63, Subpart R-National Emission Standards for Gasoline Distribution Facilities. Conoco proposed to install a gasoline vapor collection system and enclosed flare for the reduction of Hazardous Air Pollutants (HAPs) resulting from the loading of gasoline. The vapor combustion unit (VCU) was added to the bulk gasoline and distillate loading rack. The gasoline vapors are collected from the trucks during loading, then routed to an enclosed flare where combustion occurs. This project resulted in an overall reduction in the amount of actual emissions of VOCs (94.8 tpy). The reduction in potential emissions of VOCs is 899.5 tpy, while CO increases to 19.7 tpy and NO_x increases to 7.9 tpy emissions.

Conoco also requested an administrative change be made to Section II.F.5, that would bring the permit requirements in alignment with the monitoring requirements specified by 40 CFR 60, Subpart QQQ and 40 CFR 61, Subpart FF.

Because Conoco's bulk gasoline and distillate loading rack VCU is defined as an incinerator under MCA 75-2-215, a determination that the emissions from the VCU will constitute a negligible risk to public health was required prior to the issuance of the permit. Conoco and the Department identified the following hazardous air pollutants from the flare, which were used in the health risk assessment. These constituents are typical components of gasoline.

1. Benzene
2. Ethyl Benzene
3. Hexane
4. Methyl Tert Butyl Ether
5. Toluene
6. Xylenes

The reference concentrations for Ethyl Benzene, Hexane, and Methyl Tert Butyl Ether were obtained from EPA's IRIS database. The risk information for the remaining hazardous air pollutants is contained in the January 1992 CAPCOA Risk Assessment Guidelines. The model performed by Conoco for the hazardous air pollutants, identified above, monitored compliance with the negligible risk requirement.

On December 10, 1997, Conoco requested a modification to allow the continuous incineration of a PB Merox Unit off gas stream in the firebox of Heater #16. Permit #2619-11 requires the production of sulfur dioxide from the sulfur-containing compounds in the PB Merox Unit off gas stream to be calculated and counted against the current sulfur dioxide limitations applicable to the (22) Refinery Fuel Gas Heaters/Furnaces group. During a review of process piping and instrumentation diagrams, Conoco identified a PB Merox Unit off-gas stream that is currently incinerated in the firebox of Heater #16. A subsequent analysis of this off-gas stream revealed the presence of sulfur-containing compounds in low concentrations. The bulk of this low-pressure off-gas stream is nitrogen with some oxygen, hydrocarbons, and sulfur-containing compounds (disulfides, mercaptans). Sulfur dioxide produced from the continuous incineration of this stream has been calculated at approximately 1 ton per year. This off-gas stream is piped from the top of the disulfide separator through a small knock out drum and directly into the firebox of Heater #16.

Conoco proposes to sample the PB Merox Unit disulfide separator gas stream on a monthly basis to determine the total sulfur (ppmw) present. This analysis, combined with the off-gas stream flow rate, will be used to calculate the production of sulfur dioxide. After a year of sampling time, and with the approval of the Department, Conoco proposes to reduce the sampling frequency of the PB Merox disulfide separator off-gas stream to once per quarter if the variability in the sulfur content is small (±250 ppmw).

In addition, to be consistent with the wording as specified by 40 CFR 63, Subpart R, the Department replaced all references to "tank trucks" with "cargo tank" and all references to "truck-loading rack" with "loading rack". Also, the first sentence in Section II.F.5 of the preconstruction permit was deleted from the permit. Conoco had requested an administrative change be made to Section II.F.5, during the permitting action of #2619-10, which would bring the permit requirements in alignment with the monitoring requirements specified by 40 CFR 60, Subpart QQQ, and 40 CFR 61, Subpart FF. The Department had approved the request and the correction was made; however, the first sentence was inadvertently left in the permit.

On April 11, 2000, Conoco requested a permit alteration to replace the B-101 thermal reactor at the Jupiter Sulphur facility, resulting in Permit #2916-12, issued June 4, 2000. The existing B-101 thermal reactor had come to the end of its useful life and had to be replaced. The replacement B-101 thermal reactor would physically be located approximately 50 feet to the north of the existing thermal reactor due to the excessive complications that would be encountered to dismantle the old equipment and construct the new equipment in the same space. Once the piping has been rerouted to the new equipment, the old equipment would be demolished. Given this construction scenario, the Department has determined that a permit condition limiting the operation of only one thermal reactor at a time was necessary. There would be no increase in emissions as a result of this action.

Title V Operating Permit

Permit OP2619-00 was issued final and effective on 07/09/02.

D. Current Permit Action

A letter from ConocoPhillips dated December 9, 2002, and received by the Department on December 10, 2002, notified the Department that Conoco had changed its name to ConocoPhillips. On October 10, 2003, the Department received a request from ConocoPhillips for an administrative amendment of OP2619-00 to update Section V.B.3 of the General Conditions incorporating changes to federal Title V rules 40 CFR 70.6(c)(5)(iii)(B) and 70.6(c)(5)(iii)(C) (to be incorporated into Montana’s Title V rules at ARM 17.8.1213) regarding Title V annual compliance certifications. The current permit action changes the name on this permit from Conoco to ConocoPhillips and updates Section V.B.3 of the General Conditions. Operating Permit **OP2619-01** replaces OP2619-00.

E. Taking and Damaging Analysis

HB 311, the Montana Private Property Assessment Act, requires analysis of every proposed state agency administrative rule, policy, permit condition or permit denial, pertaining to an environmental matter, to determine whether the state action constitutes a taking or damaging of private real property that requires compensation under the Montana or U.S. Constitution. As part of issuing an operating permit, the Department is required to complete a Taking and Damaging Checklist. As required by 2-10-101 through 105, MCA, the Department has conducted a private property taking and damaging assessment and has determined there are no taking or damaging implications. The checklist was completed on October 30, 2003.

F. Compliance Designation

ConocoPhillips was last inspected on June 22, 2001. ConocoPhillips was in compliance with permit limitations and conditions.

SECTION II. SUMMARY OF EMISSION UNITS

A. Facility Process Description

The Billings Refinery consists of the main refinery area, where crude is broken down into various petroleum products; a truck loading rack, where gasoline and distillate is loaded into tank trucks; a wastewater treatment facility; a tank farm; a coker unit; and the sulfur recovery facility.

B. Emission Units and Pollution Control Device Identification

Emission Unit 001 is the Boiler House Stack. This stack brings together the emission gas streams from Boilers #1, #2, #B-5, and #B-6. This stack does not have control equipment, but it does have a CEM for SO_2 and a volumetric flow rate monitor.
Emission Unit 002 is the Fluid Catalytic Cracking Unit (FCCU) Stack. This stack carries emissions from the FCCU, which includes a regenerator. The FCCU does not have SO_2 control equipment, but does have a SO_2 CEM, volumetric flow rate monitor and an opacity monitor.

Emission Unit 003 is a combination of the 22 fuel gas combustion units at the refinery. The control on some of these units is Low and Ultra-Low NO_x burners. These units are also required to have a H_2S CEM.

Emission Unit 004 is the PMA Process Heater (H-3201) & Storage-Tank Vent. This unit has a Low-NO_x burner with Flue Gas Recirculation (FGR). The heater shall burn only natural gas as fuel.

Emission Unit 005 is the Refinery Flare. This unit is actually considered a "control device" in and of itself. This particular flare is equipped with a steam injection system.

Emission Unit 006 is the Refinery Fugitive Emissions. This includes numerous units and is, for the most part, concerned with leaks. Controls are the seals, gaskets, packing, and plugs.

Emission Unit 007 is the Sulfur Recovery Unit (SRU) or Facility. This includes the Jupiter SRU flare, Clause units, and SRU incinerator. The flare is steam injected and the incinerator is equipped with low-NOx burners. These units have a SO_2 CEM, O_2, and volumetric flow rate monitor.

Emission Unit 008 is Storage Tanks. These tanks must meet requirements of floating roofs with seal systems, or fixed roofs with rooftop vacuum breaker vents. These units undergo regular inspections.

Emission Unit 009 is the Product Bulk Loading. This unit is required to have a vapor collection system as well as a vapor combustion unit for control of VOCs. In addition, there are requirements for valves, flanges, pump seals, and open-ended lines.

Emission Unit 010 is the Wastewater Treatment. This unit consists of various units and requires a CPI Separator with carbon canisters to reduce VOC emissions by 95%.

Emission Unit 011 is Miscellaneous Process Vents. This includes various units. Controls depend on the type of vent and include the use of a flare or combustion device, if controls are used.

SECTION III. PERMIT CONDITIONS

A. Emission Limits and Standards

Emission limits and standards in the Title V permit were established from the preconstruction permit, the Billings/Laurel SIP, NSPS requirements, NESHAP requirements, MACT requirements, and Supplemental Environmental Projects (SEPs). Section III.A.14 was added to the final Title V permit (the following conditions in that section were renumbered) and Section III.I.20(e) was clarified per the Settlement Stipulation and Order of Dismissal ordered on July 9, 2002 by the Board of Environmental Review. The Settlement Stipulation and Order of Dismissal were associated with ConocoPhillips's appeal of Title V permit OP2619-00.

B. Monitoring Requirements

ARM 17.8.1212(1) requires that all monitoring and analysis procedures or test methods, required under applicable requirements, be contained in operating permits. In addition, when the applicable requirement does not require periodic testing or monitoring, periodic monitoring must be prescribed that is sufficient to yield reliable data from the relevant time period that is representative of the source's compliance with the permit.

The requirements for testing, monitoring, recordkeeping, reporting, and compliance certification sufficient to assure compliance, does not require the permit to impose the same level of rigor for all emission units. Furthermore, it does not require extensive testing or monitoring to assure compliance with the applicable requirements for emission units that do not have significant potential to violate emission limitations or other requirements under normal operating conditions. When compliance with the underlying applicable requirement for an insignificant emission unit is not threatened by lack of regular monitoring and when periodic testing or monitoring is not otherwise required by the applicable requirement, the status quo **(i.e., no monitoring)** will meet the requirements of ARM 17.8.1212(1). Therefore, the permit does not include monitoring for insignificant emissions units.

The permit includes periodic monitoring or recordkeeping for each applicable requirement. The information obtained from the monitoring and recordkeeping will be used by the permittee to periodically certify compliance with the emission limits and standards. However, the Department may request additional testing to determine compliance with the emission limits and standards.

In the case of CEMS, and required back-up or alternative methods when the CEMS are not running, the permit states "the Department shall approve such contingency plans." When such contingency plans are in use and have been submitted, the source will be considered to be in compliance with the contingency plan requirement until the Department informs ConocoPhillips otherwise.

C. Test Methods and Procedures

The operating permit may not require testing for all sources if routine monitoring is used to determine compliance, but the Department has the authority to require testing if deemed necessary to determine compliance with an emission limit or standard. In addition, the permittee may elect to voluntarily conduct compliance testing to confirm its compliance status.

D. Recordkeeping Requirements

The permittee is required to keep all records listed in the operating permit as a permanent business record for at least 5 years following the date of the generation of the record.

E. Reporting Requirements

Reporting requirements are included in the permit for each emission unit and Section V of the operating permit "General Conditions" explains the reporting requirements. However, the permittee is required to submit semi-annual and annual monitoring reports to the Department and to annually certify compliance with the applicable requirements contained in the permit. The reports must include a list of all emission limit and monitoring deviations, the reason for any deviation, and the corrective action taken as a result of any deviation.

To eliminate redundant reporting, a source may reference previously submitted reports (with at least the date and subject of the report) in the semi-annual and annual reports instead of resubmitting the information in monthly, quarterly, and/or other reports. However, a source must still certify continuous or intermittent compliance with each applicable requirement annually.

SECTION IV. FUTURE PERMIT CONSIDERATIONS

A. MACT Standards

As of the date of decision, 40 CFR 63, Subparts R and CC are applicable to the ConocoPhillips Refinery. The following proposed or due to be promulgated by EPA MACT standards are potentially applicable to the ConocoPhillips Refinery: 40 CFR 63, Subparts DDDDD (Industrial/Commercial/Institutional Boilers and Process Heaters) and EEEE (Organic Liquids Distribution (non-gasoline)).

B. NESHAP Standards

As of the date of decision, 40 CFR 61, Subpart FF, is applicable at the ConocoPhillips Refinery. The Department is not aware of any proposed or pending NESHAP standards that may be applicable.

C. NSPS Standards

As of the date of decision, 40 CFR 60, Subpart A, J, Ka, Kb, UU, GGG, and QQQ are applicable at the ConocoPhillips Refinery. The Department is not aware of any proposed or pending NSPS standard that may be applicable.

D. Risk Management Plan

As of the date of decision, this facility does exceed the minimum threshold quantities for any regulated substance listed in 40 CFR 68.115 for any facility process. Consequently, this facility is required to submit a Risk Management Plan.

If a facility has more than a threshold quantity of a regulated substance in a process, the facility must comply with 40 CFR 68 requirements no later than June 21, 1999; 3-years after the date on which a regulated substance is first listed under 40 CFR 68.130; or the date on which a regulated substance is first present in more than a threshold quantity in a process, whichever is later.